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VOICE OF THE ELECTRIC UTILITY INDUSTRY

PSNH falls, LILCo sways; hit by stalled N-plants

Seabrook costs topple owner

Mark T. Hoske
Assistant Editor

MANCHESTER, NH—It's more than a $64,000 question.

Will a bankruptcy-law judge do what a state supreme court and legislators would not—restore Public Service of New Hampshire's financial solvency by raising rates to recoup Seabrook costs prior to operation? No one's sure, but we're going to find out—hearings were scheduled to start in late February.

On Jan. 28, PSNH became the first utility in more than 50 years to file for protection under Chapter 11 of the Federal Bankruptcy Act.

The action came two days after the state supreme court turned down a plea to declare unconstitutional a state law prohibiting recovery of Seabrook costs in rates prior to commercial operation. That would have allowed an emergency $70-million (15-percent) rate increase, the cash PSNH said it needed to avert the filing. The state legislature also turned down requests to change the law.

What happens to whom

Because of the lack of precedence, it's uncertain what actions the court will pursue over what period of time.

Unsecured debt holders could lose portions or all of their investments, though a majority of creditors must accept any court-approved reorganization. Nuclear opponents plan to use the filing as an argument against Seabrook licensing, though the Nuclear Regulatory Commission said it's not a consideration. And, analysts say, other cash-strapped utilities will watch to see if such a voluntary filing could be an option for their future.

Protection from creditors

Company officials and some analysts express guarded optimism after the filing, because of the protection offered against the possibility of creditors seizing assets through litigation, after PSNH's default on interest payments.

PSNH's top executive spoke of the action as a part of a bigger picture.

"We'd like to emphasize that our voluntary Chapter 11 filing is but one element of our plan to restore our company's financial integrity," said President and Chief Operating Officer Robert J. Harrison.

Prior to filing, PSNH had numerous discussions on reorganization with major creditors. Now company officials will work with the court to pursue reorganization, but will be allowed to act on ordinary post-petition financial affairs without judicial approval.

Under Chapter 11, interest payments are not required, subject to the court's discretion. Annual savings on interest payments could amount to in excess of $100 million; prior to filing, the utility had previously defaulted on more than $47 million of such payments.

Although paychecks for the utility's 2600

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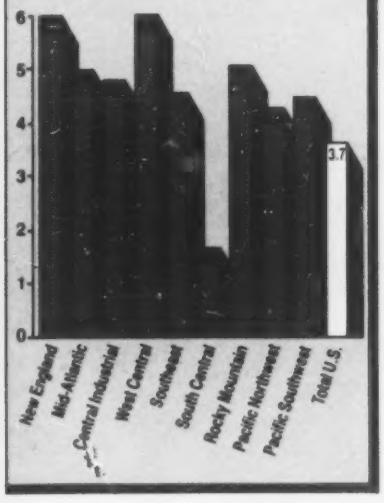
ELECTRICAL OUTPUT

Here are the increases in electric output for 1987 (from 1986) for the contiguous 48 states and for ten geographical regions, as reported by the Edison Electric Institute. The figures represent percentage increases in net total outputs of investor-, cooperative-, public- and government-owned utilities. Note that the largest increases were in the six New England and the West Central states (6.0 percent), while the smallest increase (1.7 percent) was in the South Central region.



Shoreham plan; funds 'OK' till '89

HICKSVILLE, NY—While an NRC board recently gave poor reviews to a 1986 Long Island Lighting Co. Shoreham emergency plan, the state and utility have been discussing power needs for Long Island that may not include the politically stalled plant.

Talks are confidential at this point and described as preliminary, said James Lois, a LILCo spokesperson. Discussions may anticipate a state public service commission stipulation that a rate increase would only be considered if LILCo suggests solutions to the island's energy shortage without the Shoreham plant.

Lois said LILCo will not give up on the $5.2-billion plant, but admits to needing another rate increase. The utility already is collecting $1.8 billion of construction costs in rates, reported Francis Rivett, of the New York Public Service Commission. Despite that, Lois said, after this year, cash runs out for interest payments on debts.

Rivett added that, prior to considering a rate review, LILCo would have to address a number of points, including adding power without Shoreham and improving efficiency in 215 areas.

Meanwhile, Shoreham interest, oper-

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LATE NEWS

FERC denied a rehearing of the case allocating power from the Middle South Utilities Inc. Grand Gulf 1 nuclear unit to four subsidiaries. FERC recently reaffirmed the June 1985 split. Those requesting the rehearing included state regulators and New Orleans.

Commonwealth Edison Co., with $7.1 billion invested in its three latest nuclear plants, is meeting privately to try to negotiate an acceptable rate hike. Illinois regulators have denied a complex rate-hike package; a summer vote on a 27% rate hike is expected. Opponents request a rate decrease.

A federal judge tossed out a case by the Wabash Valley Power Association that claimed PS of Indiana violated securities laws by selling WVPA 17% interest in the since-cancelled Marble Hill nuclear project. A suit is pending on a racketeering charge stemming from the long-standing dispute.

Omaha Public Power District approved an out-of-court settlement of a lawsuit against the Burlington Northern Railroad on pre-1986 coal delivery rates. The railroad will pay $21.5 million to OPPD in reparation for alleged overcharges. About 25% will go to other Nebraska utilities that shared in the original costs.

New York buys 1000-MW of firm power from H-Q

NEW YORK—The New York Power Authority and Hydro-Quebec have agreed in principle to a 1000-MW firm-power purchase, starting in 1995. If approved, it would be the largest block the Canadian provincial utility has ever arranged for U.S. usage.

Savings for state utilities, in 1990 dollars, is estimated at $550 million—at least a 10 percent savings over building that generating capacity, explained Stephen Shoenholz of NYPA.

Total revenue for H-Q, in 1990 dollars, is estimated at $3.6 billion. Amounts may change in the first year, according to power plant costs and interest rates. Inflation can adjust the amounts throughout the agreement, said Shoenholz.

The agreement would start in May 1995 with 500 MW and double a year later. Each part would be available for

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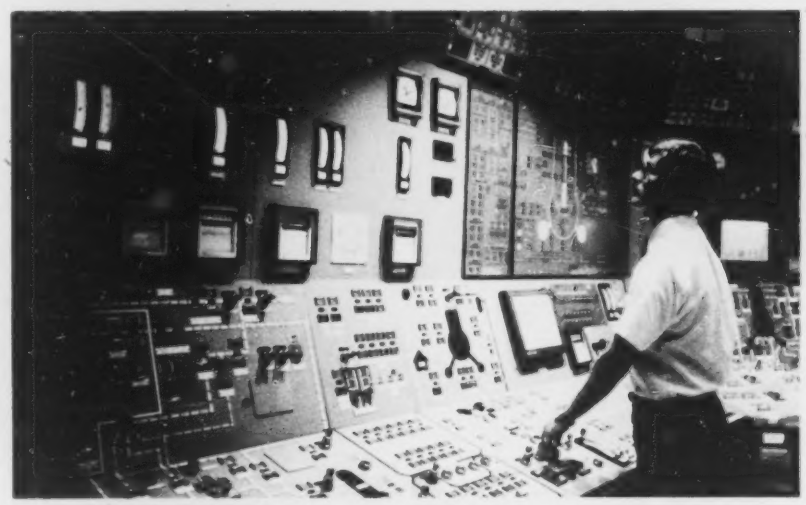

Detroit Edison's Fermi-2 goes commercial

Detroit Edison's $4.57-billion, 1100-MW Fermi-2 nuclear plant began commercial operation in late January, causing an estimated five-year $403-million (14%) rate increase. Another $298-million increase was before the Michigan Public Service Commission, as of press time. DE is protesting $397 million in disallowed costs but will write off about $340 million for Fermi-2 in the first quarter. Anticipating a first-quarter loss, DE is in "the most extensive cost-reduction program in its 80-year history," an executive said. Fermi-2, which will shut down for more tests, expands DE capacity to 9800 MW.

Coming in April

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News Briefs

BPA takes steps toward selling WNP 1 and 3

Bonneville Power Association asked for a declaratory judgment lawsuit which could make way for cancellation of the mothballed Washington Public Power Supply System nuclear projects 1 and 3.

BPA administrator Jim Jura wants to ensure that terminating the projects and selling their assets won't lead to default on $3.7 billion in construction bonds, which could require immediate payment and cause an infeasibly large increase in BPA power rates.

After months of review, the BPA asked the Department of Justice to file the suit to clear the way for a future decision. BPA would continue making monthly principal and interest payments if it decided to terminate a project.

Jura stated: "I believe...that continued preservation of the plants [is] the most prudent course of action." However, recent BPA studies show just a 34-percent chance that one of the plants would be needed to meet electric loads of the late 1990s, and just a 16-percent chance that both would be needed.

WNP 3 is 75-percent complete; WNP 1 is 65-percent complete. Bonds are paying maintenance costs of WNP 1. Projected 1988 costs of maintaining WNP 3 is $14.4 and should remain steady in future years, a spokesman said. That's down from $42.2 million in 1986, he said.

Dominion Resources' firm buys one half of Louisiana hydro plant

Dominion Capital, a subsidiary of Virginia Power's parent company, Dominion Resources, signed a partnership with Catalyst Energy Corp. for the Sidney A. Murray Jr. Hydroelectric Station, a 192-MW facility under construction on the Mississippi River in Louisiana. Dominion Capital Inc. bought half of the $500-million project.

Dale Hopke, a vice president with Dominion Capital, mentioned that the deal was made because of its investment potential and was unrelated to Virginia Power's electric service.

The firms are working with the town of Vidalia, LA, to build the power station in Concordia Parish, LA, 45 miles south of Vidalia and 100 miles northwest of New Orleans. The facility has been under construction since February, 1987, and is 25-percent completed. CE is an independent power producer that owns and leases generation facilities.

Ebasco Contractors Inc. is providing construction services under a fixed-price, fixed-schedule contract. Electricity is to be sold under a 43-year fixed-price agreement to the town of Vidalia and to Louisiana Power & Light Co., a Middle South Utilities Inc. subsidiary.

Kansas utilities want lower-sulfur coal

Kansas City Power & Light Co. and Kansas Gas & Electric Co. have asked for contractual changes with Pittsburg and Midway Coal Mining Co. in order to comply with a new state air quality control requirement.

The petition for declaratory judgment filed at a district court says P&M refuses to reduce deliveries of high-sulfur coal from its Midway Mine to La Cygne Unit 1 except at a penalty price. KCP&L operates the plant and shares ownership equally with Wichita-based KG&E.

The utilities said that recent sulfur dioxide emission tests show that burning only Midway coal would violate hourly monitoring, required starting in May, because of variances in P&M coal characteristics. To make room for lower-sulfur coal, needed for an allowable blend, the utilities want to cut P&M daily delivery from 6500 to 2500 tons.

KCP&L's David Martin said earlier efforts to resolve the matter failed. No hearing schedule had been set as of press time. In the interim, short-term purchases of lower-sulfur coal to blend with P&M coal will be made to comply, Martin said.

Palo Verde-3 becomes operational in record time

According to Arizona Nuclear Power Project (ANPP) officials, Unit 3 of the project's Palo Verde nuclear generating station set an industry record by completing its systems check-out process in 43 days. "It's nice to set a record, but far more important, it underscores the tremendous benefit of standardized plants," stated ANPP Executive Vice President Ed Van Brunt. "Because all three Palo Verde units are identical, we were able to apply to Unit 3 what we had learned on Units 1 and 2," he explained. The Nuclear Regulatory Commission granted a full power license for Palo Verde-3 in late November and, according to ANPP, the unit is expected to operate at full power throughout 1988. Arizona Public Service Company is the managing partner and operator of Palo Verde.

FERC alters split of cancelled cost

Customers and shareholders will now evenly split the cost of abandoned projects that would have been involved in FERC-regulated wholesale transactions, says a new Federal Energy Regulatory Commission policy. The new ruling changes policy that, in some previous cases, had favored shareholders.

The change affects prudently incurred costs of projects that would have been involved in selling power wholesale across state lines—not most state-regulated projects. Utilities under FERC had been able to pass on expenses from cancelled plants to ratepayers over several years, but could not earn a return on the lost investment.

Under the new policy, utilities will be able to earn a return on the portion of expenses the customers pay, but shareholders will have to write off their portion as a loss. Ratepayers will pay their share over the estimated life of the planned plant, eliminating varied periods from case to case.

NPPD exec says weigh all facts on low-level radwaste storage site

Nebraska Public Power District President and CEO Don Schaufelberger is urging state and local governing bodies and other groups to consider all the information that is available on low-level radioactive waste storage sites, before deciding to oppose the location of one in their area. "Governor Orr has proposed an informational campaign on the issue and Nebraska Public Power District is prepared to make its personnel and resources available to publicly discuss low-level radioactive waste, the type of disposal facility that would be built in the state as well as radiation and nuclear power in general," said Schaufelberger. "An emotional issue of this magnitude can result in widespread misunderstanding if the public does not avail itself to all the information available," he stressed. Schaufelberger expressed concern over the increasing number of county boards and natural resource district boards that are taking action to oppose the site location, after receiving only limited information on the issue.

DOE names seven sites as 'best qualified' to house Super Collider

Secretary of Energy John S. Herrington has announced that a list of sites for the Superconducting Super Collider has been finalized. The seven sites recommended by the National Academies' of Sciences and Engineering include: Arizona, Colorado, Illinois, Michigan, North Carolina, Tennessee and Texas. Herrington said that a preferred site will be designated in July 1988 and a final site will be announced in January 1989. According to the Department of Energy, the super collider will cost approximately $4.4 billion, with an annual estimated operating budget of $270 million.

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No increase in '86-7 winter bills, says survey

WASHINGTON—Winter residential electric bills in 1986-87 varied as much as 300 percent regionally, though the average cost per kilowatthour did not increase over the previous winter, according to the ninth winter electric bill survey conducted by the National Association of Regulatory Utility Commissioners.

Costs ranged from 4 cents per kWh in Spokane, WA, to 13.1 cents per kWh in New York, and averaged 8.1 cents per kWh nationally. Costs did not change appreciably over 1985-86, despite a 2-percent jump in the Consumer Price Index, NARUC reported.

Service areas in the U.S. Department of Energy's Northeast and Pacific regions were the most expensive, while those in the Northwest and Rocky Mountain regions were the least expensive (see map and charts).

The survey covers bills from December 1986 through February 1987 for 250, 500, and 750 kWh for 191 service territories in 49 states and the District of Columbia. It also covers costs for customers with electric space heating but compiles results only for 500 kWh. Nebraska, which is served only by publicly owned utilities, does not regulate electric rates so is not included.

Copies of the 203-page report are available for $17 from NARUC, P.O. Box 684, Washington, D.C., 20044.

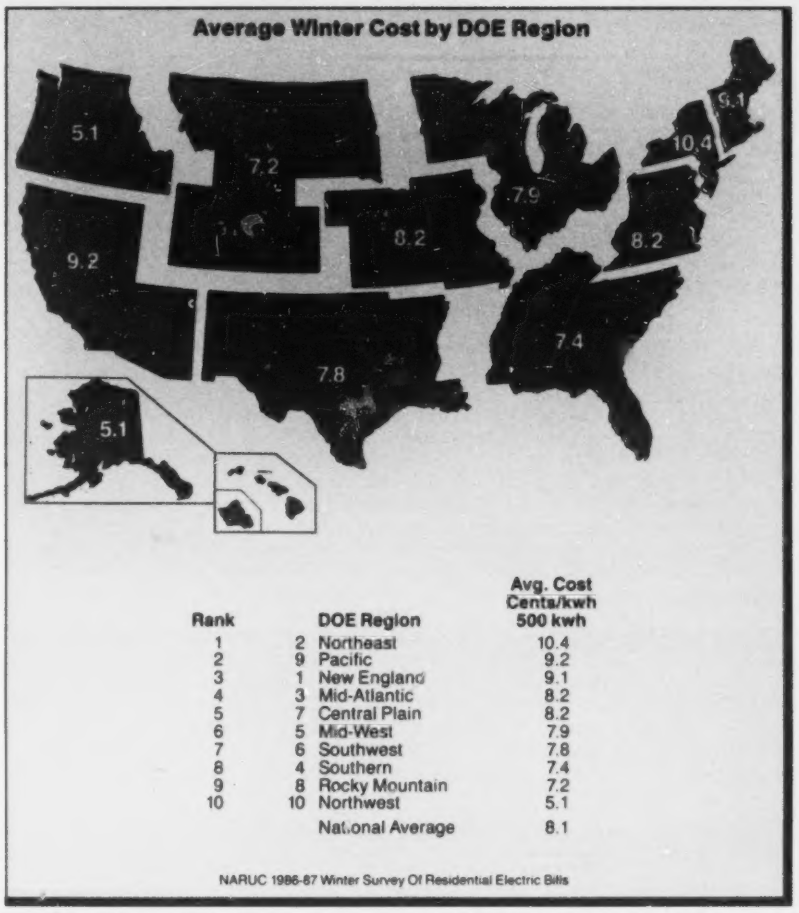
Ten Most Expensive Service Territories
(Continental U.S.)

Company	State	Total Bill	Avg. Cost Cents/kwh 500 kwh	Rank
Consolidated Edison Co. Of N.Y.	New York	$195.91	$0.131	1
San Diego Gas & Electric	California	$179.91	$0.120	2
Long Island Lighting	New York	$177.56	$0.118	3
Philadelphia Electric	Pennsylvania	$175.87	$0.117	4
Orange & Rockland Utilities	New York	$168.77	$0.113	5
Texas-New Mexico Power	New Mexico	$167.33	$0.112	6
Central Vermont Public Service	Vermont	$166.80	$0.111	7
Delmarva Power & Light	Virginia	$164.82	$0.110	8
Public Service Elec. & Gas	New Jersey	$162.36	$0.108	9
Northern Indiana Pub. Service	Indiana	$162.09	$0.108	10

Ten Least Expensive Service Territories
(Continental U.S.)

Company	State	Total Bill	Avg. Cost Cents/kwh 500 kwh	Rank
Washington Water Power	Washington	$ 59.97	$0.040	191
Washington Water Power	Idaho	$ 62.73	$0.042	190
Idaho Power	Idaho	$ 63.17	$0.042	189
CP National Corp.	Oregon	$ 65.85	$0.044	188
Pacific Power & Light	Washington	$ 67.95	$0.045	187
Idaho Power	Oregon	$ 71.34	$0.048	186
Portland General Elec.	Oregon	$ 72.84	$0.049	185
Pacific Power & Light	Montana	$ 73.32	$0.049	184
Puget Sound Power & Light	Washington	$ 75.74	$0.050	183
Minnesota Power & Light	Minnesota	$ 79.48	$0.053	182

Source: NARUC 1986-87 Winter Survey Of Residential Electric Bills



Rank		DOE Region	Avg. Cost Cents/kwh 500 kwh
1	2	Northeast	10.4
2	9	Pacific	9.2
3	1	New England	9.1
4	3	Mid-Atlantic	8.2
5	7	Central Plain	8.2
6	5	Mid-West	7.9
7	6	Southwest	7.8
8	4	Southern	7.4
9	8	Rocky Mountain	7.2
10	10	Northwest	5.1
		National Average	8.1

NARUC 1986-87 Winter Survey Of Residential Electric Bills

Pilgrim outage; charges mount

CAMBRIDGE, MA—Boston Edison Co.'s 678-MW Pilgrim plant, shut down since April 1986, has left several neighboring utilities to buy power elsewhere, sparking charges of BE imprudence and legal action.

BE denies the charges and, as of press time, planned to have the plant ready for operation by early March, but may have to wait until May or longer for an NRC go-ahead.

Total cost for replacement power has surpassed $170 million, according to BE's $250,000-a-day estimation.

Commonwealth Electric Co., which has a contract to buy 70 MW (11 percent) of Pilgrim's power, filed a petition with the Federal Energy Regulatory Commission, asking for a full investigation, saying BE has failed to manage the plant prudently and diligently in this and prior shutdowns.

Demands outlined

CEC also asked for a refund of unjustified contract-related charges and payment of additional costs for replacement power, permission to terminate the contract, or an order that the contract be changed to protect CEC and its customers in the future, explained Russell D. Wright, financial vice president of CEC's parent, Commonwealth Energy System. CEC filed similar complaints with the U.S. Federal Court for the District of Massachusetts, he said.

In a counterfiling with FERC, BE de-

continued on page 7

NRC gets Peach Bottom plan; president quits after INPO audit

PHILADELPHIA—Philadelphia Electric Co. delivered the second half of its nuclear reorganization plan to the NRC in mid-February and hopes to reopen its Peach Bottom nuclear plant by this summer. The 886-MW nuclear plant has been closed a year.

Until Peach Bottom restarts, Corbin A. McNeill Jr., senior vice president nuclear with Public Service Electric & Gas Co., has been loaned to PE to fill the newly created position, executive director of nuclear. Like plant operator PE, PSE&G owns 42.5 percent of Peach Bottom. Delmarva Power & Light Co. and Atlantic Electric Co. each own 7.5 percent.

Partly in response to a scathing Institute of Nuclear Power Operations review of management actions concerning the Peach Bottom shutdown, John H. Austin Jr., with PE for 38 years, resigned.

PE's Bill Jones said a national search has commenced for a new president with strong nuclear experience. James L. Everett III, PE's chairman and chief executive officer, is filling the position in the interim.

State regulators, handing PE a $37 million rate cut, called for Everett's resignation. As of press time, PE had not officially responded.

After shutdown, the utility was criticized strongly by the Nuclear Regulatory Commission about Peach Bottom and management.

INPO downgrades PE efforts

Following its review, INPO said PE's initial reorganization accomplished little. Submitted in September, it restructured the chain of command to emphasize nuclear operations and was later approved by the NRC (*EL&P*, Nov. 1987, p.43).

Report's effect

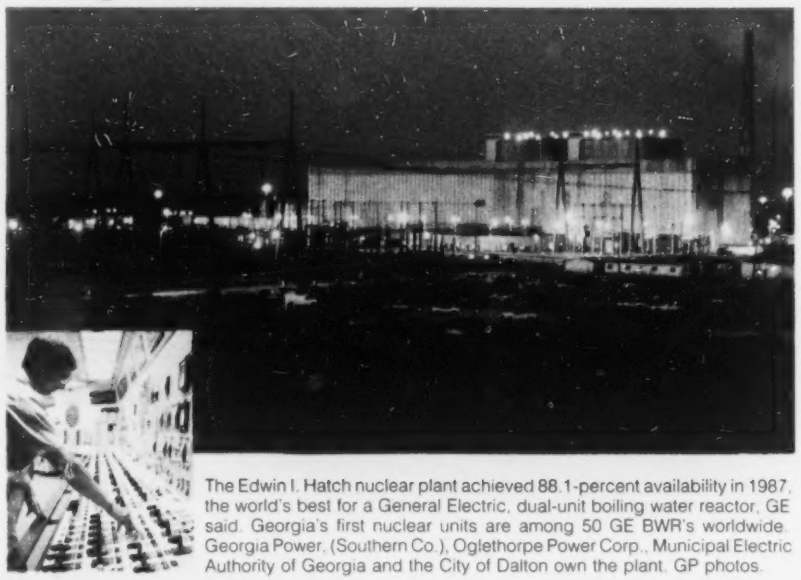
An NRC spokesperson for PE's region reported that he was unsure how INPO's recent report would affect the NRC's evaluation of the Peach Bottom restart plan.

Jones said this plan, the second half of PE's reorganization, would improve Peach Bottom training, company communications, and accountability. These were among INPO's main concerns.

Replacement power cost

The Peach Bottom shutdown has cost PE more than $58 million in replacement power so far. The plant was shut down in March 1987 after the NRC learned that operators had napped in the plant's control room. Later concerns about PE management were revealed.

Georgia Power's Hatch Plant sets record



The Edwin I. Hatch nuclear plant achieved 88.1-percent availability in 1987, the world's best for a General Electric, dual-unit boiling water reactor, GE said. Georgia's first nuclear units are among 50 GE BWR's worldwide. Georgia Power, (Southern Co.), Oglethorpe Power Corp., Municipal Electric Authority of Georgia and the City of Dalton own the plant. GP photos.

COMMENTARY

Keep PSNH problems in proper perspective

It would be wrong to try to minimize the seriousness of the problems confronting Public Service Company of New Hampshire. It also would be equally improper not to keep that company's difficulties in proper perspective.

Obviously, when a utility is forced to seek Chapter 11 bankruptcy protection, it's a serious problem. But it's the problem of just one utility, and not a typical utility even then. It is not an industry problem and doesn't suggest troubles for other utilities, not even nuclear utilities.

PSNH got into its financial difficulties because of two things: the Seabrook Nuclear Plant and company management's refusal to abandon it when skyrocketing costs outran the company's abilities to fund them. PSNH assets still exceed liabilities by more than $1-billion. It just can't generate enough cash to service its Seabrook debt. But unless the NRC grants Seabrook its operating license without an official emergency plan submitted by the Commonwealth of Massachusetts, that may never occur.

The bankruptcy action will provide the utility with time in which to work out solutions to its other problems. Service to customers will continue. Employees will continue to be paid. If interest payments are suspended, as typically done, the company will improve its cash flow by more than $100-million per year.

However, a number of difficult questions must be answered. Will the bankruptcy court judge be able to establish needed higher rates for the utility? If the court should try, how will the state utility commission, which is specifically charged with rate regulation, respond? Should the court defer to the state commission to direct an increase, would the commission set rates high enough to allow the utility to earn a fair rate of return? And how will shareholders respond to the probability that creditors will be granted major controlling interest in the company?

There is no question the next few years will be difficult for PSNH personnel and others related to the company. But it's vital to keep those troubles in perspective.

Challenges face co-ops

After a lapse of more than a decade, this editor again was privileged to cover the Annual Meeting of the National Rural Electric Cooperative Association held in New Orleans last month. The 46th annual gathering of co-op managers and directors was a smoothly organized, well-run business meeting that focused heavily on the economic and technical changes facing co-ops and the electric industry at-large. It was interesting and valuable, but with few of the histrionics and verbal pyrotechnics of earlier years.

Back in the 60s and 70s, NRECA General Manager Clyde Ellis and strings of rural representatives from Congress sizzled the air with charges against investor-owned utilities and conservative administrations, waving the flag for country, family-based social values, the rural life and the co-op spirit that brought people together to do for themselves what big business couldn't or wouldn't do. Those were meetings replete with oratory, the kind of stem-winding invocations against big business and the IOUs that brought crowds to their feet and filled the halls with cheers and jeers.

This year, however, there was little of the hoopla and verbal fireworks of those earlier days. Instead, presentations focused on the specific needs of small electric systems, as represented by co-ops, and how developments in the society and economy will impact those small systems. Subjects like how rural America can adapt to the high-tech, high-flex society, deregulation, building load, pricing and management competence drew large audiences and lively questioning. Appeals were far more to the intellect than to emotion.

Another difference was that registrants seemed older and talked and acted more conservatively, despite the influence of the French Quarter, than I recall from earlier meetings. But maybe that's because I'm older and more conservative (yes, even with the French Quarter right around the corner), and tend to recognize those characteristics in others.

In any case, it was a thought-provoking three-day session, providing the kinds of information and background needed for intelligent decision-making in the months and years ahead... more useful than those I recall from the past.

But I did miss the excitement.

Robert A. Lincicome, Editor-in-Chief

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LETTERS

Reader response to EL&P letter

A copy of the following letter was sent to *EL&P* as a followup to a letter about PCB testing written last spring by the head of the PCB disposal section at EPA and published in *Electric Light & Power*.

Dr. John H. Smith, Chief
PCB Disposal Section
U.S. Environmental Protection Agency
Washington, DC 20460

Dear Dr. Smith,
Earlier this year I recall seeing your letter (on PCB testing) in *Electric Light & Power* (March 1987, p.3).

Let me tell you a story.

A few years ago, a college student working part-time at a utility was told to clean up a PCB spill.

Despite published company procedures, providing for the use of clean-up gloves, etc., he was given nothing, nor was he told about the potential carcinogen exposure.

In fact the clothing he wore that day, including his boots, which were saturated with PCB-contaminated oil, was worn home.

When he learned about PCBs, he contacted the utility company, in writing, asking for more information. He was told, in a letter prepared for [a company executive's] signature by [the company's] outside law firm, that he need not worry, since his exposure level was less than 150 ppm.

In fact, the exposure level reported by the utility to EPA for this spill was more than 8500 ppm.

Inquiries to EPA resulted in suggestions that the state's Water Control Board be contacted. They, in turn, suggested that it wasn't in their area and that he contact the state Attorney General's office.

The Attorney General advised that while the employee had been lied to, the company had not lied to EPA, hence there was nothing that could be done.

A classic study of bureaucracy. Let me assure you that the very top management of this "respected" utility were made aware of this. So, while the young man waits...and wonders...the criminals, (and in my opinion no other word fits better) go free.

I know about this matter since the young man involved is my son.

Cary Cohen
Caldwell Consulting Associates
Richmond, VA

LTC selection

It is noted in the article "Evaluation method can ease LTC selection," (October 1987, p.30) that the arguments presented are those of a representative of ASEA Electric. I cannot fault him for promoting any features of his client's product. However, as an engineering manager with a producer of a family of tapchangers based on the reactance bridging-in-oil concept used by several OEM of LTC transformers, I must challenge or expand on several points.

First, to clarify, the article shows a tapchanger identified as the Siemens TL3, rated at 1200 amperes. Neither of these is correct. I believe the article is referring to our TLH-21 tapchanger, rated at 1300 amperes.

Regarding inspection costs, the article assesses the expense of two inspections per year to reactance/oil tapchangers. Siemens literature recommends only that the *first* inspection be made at 6 months or 50,000 operations, whichever comes first. Based on the observations of that check, our literature suggests that "two or three years may be allowed" until the next check of the mechanism. It also should be recognized that the frequency of checks is more a function of operation count than of elapsed time. With only 5500 operations planned per year, the user will very soon find that even a three-year interval of inspections is unnecessary.

Also in the context of inspection costs, why is it that the present value[s] of costs are shown in the article to remain unchanged by year?

Regarding the number of tapchanger operations between contact replacement, the article indicates contact replacement on the Siemens tapchanger at intervals of 55,000 operations. While we have been reluctant to state a specific life for the contacts, our literature does state "typical values of arcing contact life range from 100,000 to 1,000,000 load tapchanging operations." Consequently, the article indicates three changers in the 165,000 operation (30-year) period, when our *most conservative* estimate would indicate only one change would be required.

Our hesitation to be more definitive regarding guaranteed operations stems from the variability in operating conditions to which the tapchanger would be subjected. For example, if the tapchanger is operated nominally at 800 a. instead of the rated 1300 a., the life expectance is raised about 84 percent; if the system load power factor is 0.95 lagging instead of the basis 0.80 lagging, the life expectance is raised about 13 percent. Additionally, the transformer manufacturer can design the tap voltage and bridging reactor exciting current to affect the contact life.

Regarding transformer no-load losses, the article at one point states that the dollar value of losses will not be treated in the study, yet later makes a specific negative comment regarding LTC preventive autotransformer core losses. This section reads as though there is something particularly detrimental about losses associated with the PA. Of course, when losses are quoted for the transformer they include the contribution of the PA.

Ironically, it is the question of transformer losses that often makes the most telling point when countering the claims of ASEA. Since the ASEA tapchanger is rated for a through current of only 600 a., a transformer rated higher that 600 a. would include a supplemental series transformer.

The user must be made aware of how no-load losses are greatly affected by tap position when a series transformer is used. No-load losses are frequently quoted at the neutral tap position, where the series transformer contributes nothing to to the no-load loss. In order to perform a realistic loss evaluation, the losses must be known at other tap positions. It is for this reason that the following statement has been added to an IEEE Guide for loss evaluation presently being developed.

The losses in Load Tap Changing (LTC) transformers may vary with the LTC position. In addition, at any given position, the losses may vary with different configurations of LTC equipment, such as tap winding location, the presence of series transformers, preventive auto transformers, etc. The user should consider these variations when comparing two or more offerings.

The points that I have raised relate directly to the tapchanger and its application. Very likely, the transformer manufacturers will have additional comments.

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